BEFORE
THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NOS. 2019-224-E and 2019-225-E

In the Matter of:	)
	)
South Carolina Energy Freedom Act (House Bill 3659) Proceeding Related to S.C. Code Ann. Section 58-37-40 and Integrated Resource Plans for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC	))))))

DIRECT TESTIMONY OF KEVIN LUCAS

ON BEHALF OF

THE SOUTH CAROLINA SOLAR BUSINESS ALLIANCE

REVISED
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I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A1. My name is Kevin Lucas. I am the Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association (SEIA). My business address is 1425 K St. NW #1000, Washington, DC 20005.

Q2. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.

A2. I began my employment at SEIA in April 2017. SEIA is leading the transformation to a clean energy economy, creating the framework for solar to achieve 20% of U.S. electricity generation by 2030. SEIA works with its 1,000 member companies and other strategic partners to advocate for policies that create jobs in every community and shape fair market rules that promote competition and the growth of reliable, low-cost solar power. Founded in 1974, SEIA is a national trade association building a comprehensive vision for the Solar+ Decade through research, education and advocacy.

As Senior Director of Utility Regulation and Policy, I have developed testimony in rate cases on rate design and cost allocation, in integrated resource plans on resource selection and portfolio analysis, worked on the New York Reforming the Energy Vision proceeding on rate design and distributed generation compensation mechanisms, and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy (Alliance) from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service providers that was seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University Of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, cum laude, from Princeton University in 1998.

Q3. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION?

A3. No, I have not.

Q4. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?

A4. Yes. I have testified before the Maryland Public Service Commission in several rate cases and merger proceedings. Additionally, I have testified before the Maryland Public Service Commission in several rulemaking proceedings, technical conferences, and legislative-style panels, covering topics such as net metering, EmPOWER Maryland (Maryland's energy efficiency resource standard), and offshore wind regulation development.

I have also submitted testimony in rate cases and integrated resource plans before the Public Utility Commission of Texas, the Michigan Public Service Commission, the Public

Utility Commission of Nevada, the Arizona Corporation Commission, and the Colorado Public Utilities Commission. My complete CV is attached to my testimony.[1]

Q5. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A5. My testimony is provided on behalf of South Carolina Solar Business Alliance ("SCSBA").

Q6. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A6. In my testimony, I analyze Duke Energy Carolina's and Duke Energy Progress's ("Duke" or "the Company") 2020 Integrated Resource Plan ("IRP") filing and its comportment with the requirements of Act 62. I compare and contrast Duke's IRP filing to the recently rejected Dominion Energy South Carolina ("DESC") IRP and find Duke's IRP lacking on several specific points the Commission cited in its rejection of DESC's IRP in Order No. 2020-832. I also evaluate Duke's modeling approach and assumptions on solar and storage, pointing out areas where improvements are needed, and highlight the overlooked opportunity presented by the recent extension of the federal investment tax credit ("ITC") on the Company's resource plan. Further, I deconstruct Duke's natural gas forecast, a key driver to its IRP results, and show why its approach is flawed and must be rejected. Finally, I evaluate the benefits of broader regionalization in reducing the cost for maintaining resource adequacy and facilitating the integration of more renewable energy.

Q7. PLEASE SUMMARIZE YOUR FINDINGS.

A7. Duke must make material modifications to its IRP to comport with Act 62.[2] At the broadest level, the Company does not identify "the most reasonable and prudent means of meeting [its] energy and capacity needs," instead presenting six different portfolios with disparate and flawed assumptions and results.[3] As a result, in order to perform its statutory duties, the Commission must direct Duke to amend its IRP to include such a determination or do so itself.

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[1] Exhibit KL-1, Kevin M. Lucas CV.

[2] Act 62 is the recently passed law that stipulates requirements for IRPs. The statute defines the filing process, required information, and approval criteria. This is Duke's first IRP submitted since the statue was signed into law in May 2019. S.C. Code Ann. § 58-37-40.

[3] S.C. Code Ann. § 58-37-40(C)(2).

Duke also fails to consider adding energy-only resources during years where there is no capacity need and does not use the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") energy storage costs, in direct conflict with the Commission's order rejecting DESC's IRP.

Duke also fails to present a robust risk analysis that would enable the Commission to determine if the proposed IRP is the most reasonable and prudent means of meeting the electrical utility's needs, balancing "foreseeable conditions" including "resource adequacy," "consumer affordability," "compliance with applicable state and federal environmental regulations," and "commodity price risks," as the statute requires.[4] Although Duke develops multiple scenarios and sensitivities, the risk analysis is primarily qualitative. The Company fails to adequately account for several fossil-fuel related risks, including limited availability of firm natural gas supply, regulatory risk associated with continued coal plant operation, and stranded natural gas infrastructure investments for several of its portfolios. It assumes operational dates for non-commercial technologies such as small modular reactors ("SMR") and hard-to-permit technologies such as pumped hydro that are inconsistent with its own development timelines for these projects.

Duke's IRP portfolio modeling also fails to "fairly evaluate[e] the range of demand-side, storage, and other technologies and services available to meet the utility's service obligations."[5] Duke bypassed or limited opportunities for the model to find optimal solutions, instead hardcoding many results rather than allowing the model to solve for the best solution. This was particularly true for energy-only resources, which were prohibited from selection by the model absent a capacity need. Duke's solar capital costs are reasonable, although they need to be updated based on the recent extension of the federal ITC, but its operation and maintenance ("O&M") costs do not reflect industry trends occurring in this space. The

[4] S.C. Code Ann. § 58-37-40(C)(2).
[5] S.C. Code Ann. § 58-37-40(B)(1)(e).

Company also erroneously inflates its energy storage cost assumptions, incorrectly claiming that other public forecasts do not adjust for factors such as depth-of-discharge limitations and battery degradation. It also fails to account for any benefit from shorter-duration or behind-the-meter energy storage systems. The result is a substantial overestimate of energy storage costs that may have prevented the modeling software from selecting the most cost-effective quantities.

The recent extension of the federal ITC is a major development that has not been included in the Company's IRP. While this is understandable given the extension occurred in late December 2020, the impact on the IRP's portfolios could be large enough to warrant inclusion at this point. Effectively, projects that are completed before the end of 2026 are now able to obtain higher ITCs than was assumed during Duke's IRP development. This argues in support of pulling up solar and solar plus storage procurements to capture the credit for the benefit of Duke's customers.

Aside from failing to properly analyze the risk associated with fossil fuel generation, Duke also uses highly questionable methodologies in the natural gas price forecast used in its modeling. Duke relies on financial instruments priced on illiquid and volatile ten-year market natural gas futures contract prices before shifting over five years to a fundamentals-based forecast. The result is gas prices that are substantially lower than fundamentals-based forecasts for 15 years – the entire duration of the IRP planning period. Duke also assumes available natural gas firm fuel supply at a reasonable cost despite the recent cancellation of the Atlantic Coast Pipeline ("ACP") and $1.2 billion write down of the Mountain Valley Pipeline ("MVP"). Coupled with this is a total lack of a coal fuel cost and fixed O&M cost sensitivity, despite the sizable regulatory risks associated with the continued operation of Duke's coal fleet. These fossil-fuel related risks are all asymmetrical, leading to scenarios that are more likely to understate than overstate the cost of operating a fossil-fuel-heavy fleet.

Much of Duke's modeling assumes that it operates on an islanded network with little ability to share capacity between its operating units or to import capacity from the many surrounding balancing areas. Despite this baseline assumption, Duke's own modeling shows the benefits of a more coordinated approach to planning; allowing DEC and DEP to plan as one unit delays the need to build new capacity and produces savings for its customers. Expanding this concept further through a regional market could bring even deeper savings to customers, increase the ability to integrate renewable energy, and increase reliability in extreme events.

Q8. PLEASE SUMMARIZE YOUR OVERALL RECOMMENDATIONS.

A8. I make the following recommendations with respect to Duke's IRP:

Items Related to Act 62

1. The Commission should not approve Duke's IRP but rather require modifications to comply with Act 62.
2. Duke should select a single portfolio as its most reasonable and prudent option.
3. Duke should use battery capital costs from NREL's ATB Advanced case, as was required in the DESC IRP Order.
4. Duke should allow the addition of new resources or PPAs even when there is not a capacity need, as was required in the DESC IRP Order.
5. Duke should redo its natural gas forecast methodology to deemphasize the impact of short-term market price volatility, as was required in the DESC IRP Order.
6. Duke should produce a more robust risk assessment of its proposed buildout of natural gas infrastructure, including risks associated with obtaining firm fuel supply and stranded assets.

Modeling Methodologies and Input Assumptions

7. Duke should update modeling to incorporate the impact of the extension of the federal ITC on solar and solar plus storage projects.
8. Duke should adjust its fixed O&M costs for solar to reflect the same regional discount from NREL ATB as in its capital costs and mirror its price decline over time.
9. Duke should use NREL ATB Advanced capital costs for its energy storage costs.
10. Duke should use an annual battery replenishment model for both its standalone storage and solar and storage projects.

11. Duke should not inflate its battery pack size assumptions as battery degradation and enhancement is already accounted for in NREL ATB's fixed O&M costs.

12. Duke should allow its model to select up to 1,500 MW and 1,000 MW of two-hour batteries in DEP and DEC, respectively.

13. Duke should perform an analysis to determine the actual mix of fixed-tilt and single-axis tracking systems in its territories and use that for all analyses that model existing solar.

14. Duke should update its assumptions on future builds of solar to be 100% single-axis tracking systems for large projects and at least 80% single-axis tracking systems for future PURPA projects.

15. Duke should eliminate the 500 MW per year interconnection limit for solar in all cases, instead using the higher 900 MW limits in its high renewables case.6

16. Duke should adjust the development timelines of SMR and pumped hydro to at least be consistent with its own assumptions and preferably to be more in line with development timelines from recent projects.

Natural Gas Price Forecast and Coal Price Forecast

17. Duke's natural gas price forecast should calculate three years of monthly market prices based on the average of the previous month's market settlement prices from the NYMEX NG futures contract.

18. Duke should calculate the average price from at least two fundamentals-based forecasts, at least one of which should be the most recent EIA AEO reference case.

19. Duke should create a composite natural gas price forecast by using market prices for months 1 through 18, linearly transition between market prices and the fundamentals-based forecast average from months 19 through 36, and use the fundamentals-based forecast average form month 37 forward.

20. In constructing its high- and low-price sensitivities, Duke should utilize its current "geometric Brownian Motion model" to construct 25th and 75th percentile projections for 36 months. It should also calculate the average of the appropriate high- and low-price scenario from two or more fundamentals-based forecasts and perform the same blending method over 36 months as was done in the base natural gas price forecast.

21. Duke should construct a high-cost scenario for coal that reflects the potential increase in capital costs or fixed O&M costs that may come with future regulations.

The Benefits of Regionalization

22. Duke should study the impact of enhancing its Joint Dispatch Agreement to allow for joint planning and firm capacity sharing between the DEC and DEP.

23. Duke should study potential benefits associated with forming or joining an RTO or energy imbalance market.

[6] All references to solar capacity are in MW_{AC}.

Q9. WHAT DO YOU ANTICIPATE WILL BE THE RESULTS OF YOUR COMBINED RECOMMENDATIONS?

A9. I anticipate that when Duke reruns its models with the updated methodologies and input assumptions above that optimal portfolios will retire coal sooner and build less natural gas capacity, while also selecting more solar, storage, and solar plus storage projects earlier in the planning horizon. These portfolios will be more robust against potential fossil fuel price increases and regulatory risks associated with existing and new fossil fuel assets. It will also jump start Duke's progress towards its own net-zero goals by leveraging the extension of the ITC to the benefit of its customers. The additional analysis and results will enable the Commission to determine whether it is the "most reasonable and prudent means of meeting the electrical utility's energy and capacity needs" under the statute.

II. <u>ACT 62 REQUIRES A DETERMINATION OF "THE MOST REASONABLE AND PRUDENT MEANS OF MEETING THE ELECTRICAL UTILITY'S ENERGY AND CAPACITY NEEDS AS OF THE TIME THE PLAN IS REVIEWED."</u>

Q10. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A10. In this section, I discuss Duke's IRP in the context of Act 62 and the Commission's rejection of DESC's IRP. I explain how Duke has failed to identify "the most reasonable and prudent means of meeting [its] energy and capacity needs" (i.e., a "Preferred Resource Plan"), while simultaneously failing to provide the Commission with all the information it would need to determine the most reasonable and prudent means of meeting such needs. I discuss similarities between Duke's IRP and the recently rejected DESC IRP, and critique Duke's massive natural gas buildout in the context of its net-zero carbon goals. Finally, I analyze the limited risk analyses that Duke performed and put forth a simple yet insightful risk analysis to show the benefit of retiring coal plants early.

Q11. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A11. Duke's IRP fails to comply with Act 62. By failing to select a Preferred Resource Plan, the Company is sidestepping its responsibility under the Act. Further, Duke has not presented the Commission with sufficient information to evaluate which plan is the most reasonable and prudent. Act 62 requires Duke to do more than just present a suite of options, it must also do the hard work to determine and demonstrate which of those options meets the statutory test of being the most reasonable and prudent path forward.

Duke's IRP shares several characteristics with DESC's rejected plan. Specifically, it uses unrealistic energy storage costs, fails to allow energy-only resources to be selected by the model, and inappropriately applies short-term pricing to long-term fuel cost forecasts. The Commission should reiterate its position in this case and direct Duke to make the same corrections that it required of DESC.

Despite having a 2050 net-zero goal, Duke proposes a massive buildout of natural gas infrastructure, much of which is brought online just after the 2035 IRP planning horizon ends. Duke underestimates the risk associated with its fuel supply assumptions, modeling availability at constant prices for firm gas delivery to its new natural gas combined cycle units despite the recent cancellation and write down of two local pipelines. Its stranded asset analysis is woefully inadequate if it has any intention of meeting its 2050 net-zero goals.

In the absence of a quantitative risk analysis from Duke, I produced a similar analysis as was performed in the DESC case. Here, it demonstrates the risk / benefit of both the Base Case with Carbon and the Earliest Practicable Coal Retirement portfolios under a wide variety of fuel and CO_2 cost assumptions.

A. Act 62 Requires Duke to Select a Single Most Reasonable and Prudent Plan

Q12. WHAT IS ACT 62?

A12. Act 62, also known as the SC Energy Freedom Act, was a comprehensive piece of energy legislation signed into law in May 2019,[7] includes numerous provisions on renewable energy programs, net metering, avoided cost calculation, interconnection standards, and integrated resource planning. Section 7 of the Act overhauls the requirements for integrated resource plans for electric utilities, electric cooperatives, municipally owned electric utilities, and the South Carolina Public Service Authority, and for the first time requires PSC review and approval of a utility IRP in a contested evidentiary proceeding.

Q13. WHAT ARE SOME OF THE KEY CRITERIA DEFINED IN ACT 62?

A13. Act 62 requires that covered electricity providers file an IRP at least every three years, with updates submitted annually.[8] The IRP must include information such as the long-term forecast of the utility's sales and peak demand; data related to the utility's existing resources and retirement plans; several resource portfolios to evaluate a range of demand-side, supply-side, storage, and other technologies and services available to meet the utility's obligations; and an analysis on the cost and reliability impacts of meeting projected energy and capacity needs, among others.

The Commission must hold a public hearing on the IRP in which interested parties may intervene and gather evidence. Within 300 days of the filing, the Commission must issue a final order approving, modifying, or denying the plan filed by the utility. This decision is based on whether the Commission determines that the proposed IRP "represents the most reasonable and prudent means of meeting the electrical utility's energy and capacity needs as of the time the plan is reviewed."[9]

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[7] S.C. Code Ann. § 58-37-40. Bill text accessed 1/12/2021 at https://www.scstatehouse.gov/sess123_2019-2020/bills/3659.htm.

[8] While Act 62 requires several types of electricity providers to file IRPs, my testimony is focused on the requirements for electric utilities.

[9] S.C. Code Ann. § 58-37-40(C)(2).

The Commission's decision must consider whether the plan appropriately balances several factors, including resource adequacy and planning reserve levels, consumer affordability and least cost, compliance with environmental regulations, power supply reliability, commodity price risks, diversity of generation supply, and other foreseeable conditions that the Commission determines to be for the public interest.[10] If the Commission finds the proposed IRP does appropriately balance these factors, it must approve the IRP.[11] If it does not reach this finding, it can reject or require modifications to the IRP.

Q14. DOES DUKE PRESENT A SINGLE PORTFOLIO THAT IT ADVOCATES AS THE "MOST REASONABLE AND PRUDENT MEANS" OF MEETING ITS NEEDS?

A14. No, it does not. Duke presents a suite of six resource portfolios, each with several sensitivities, that contain differing assumptions on key characteristics such as coal retirement timeline, renewable energy addition limits, carbon pricing, and fuel forecasts. Duke appears to construe the compilation of the six portfolios as its "plan" as defined by Act 62, rather than properly identifying each of the six portfolios as a "plan" to be analyzed under Act 62's balancing requirements.

The two Base Cases are described as "least cost" portfolios (one with and one without carbon policy), while the other four explore pathways under various carbon constraints.[12] The six portfolios are:

- **Base Case without Carbon Policy**: "least cost" portfolio assuming no carbon policy.
- **Base Case with Carbon Policy**: "least cost" portfolio assuming basic carbon policy.
- **Earliest Practicable Coal Retirement**: retires coal plants as soon as practicable and optimizes remaining portfolio to meet capacity need.
- **70% CO2 Reduction: High Wind**: 70% CO_2 reduction constraint is modeled with higher deployment of solar, onshore wind, and offshore wind.
- **70% CO2 Reduction: High SMR**: 70% CO_2 reduction constraint is modeled with higher deployment of solar, onshore with, and small modular reactors ("SMR").
- **No New Gas Generation**: High CO_2 reduction targeted while not adding any new natural gas generation.

[10] S.C. Code Ann. § 58-37-40(C)(2)(a-g).
[11] S.C. Code Ann. § 58-37-40(C)(2).
[12] DEC IRP Report at 11-12.

Duke's IRP Report misconstrues the South Carolina IRP requirements, claiming "[t]hese base case portfolios employ traditional least cost planning principles as prescribed in both North Carolina and South Carolina."[13]

Q15. IS "LEAST COST" PLANNING THE CURRENT SOUTH CAROLINA REQUIREMENT FOR IRPS?

A15. No. Act 62 specifically defines a different "most reasonable and prudent" standard for IRPs. While "least cost" is one of the balancing factors that the Commission must weigh, it is not confined to the least cost plan if more reasonable and prudent portfolios exist.

Q16. DOES ACT 62 REQUIRE THE IDENTIFICATION OF A SINGLE PORTFOLIO AS THE "MOST REASONABLE AND PRUDENT" MEANS TO MEETING FUTURE NEED?

A16. With the caveat that I am not an attorney and not offering a legal opinion, I believe it does. Act 62 enumerates factors the Commission must balance, including consumer affordability and least cost, commodity price risk, and diversity of generation supply.

The Commission has previously acknowledged that the utility should identify a Preferred Resource Plan in its IRP submittal. In its order rejecting DESC's IRP, it identified the steps in a common approach to IRPs as "(1) forecast future electricity demand; (2) identify the goals and regulatory requirements the process must meet; (3) develop a set of resource portfolios designed to achieve those goals; (4) evaluate those resource portfolios; and **(5) identify a preferred resource plan**."[14] It also noted that DESC "did not properly assess risk and uncertainty, as required by Act 62, when analyzing and **selecting a preferred resource plan**."[15]

By developing six different portfolios without specifying which it believes is the most reasonable and prudent, Duke has presented dramatically different futures while simultaneously providing insufficient guidance on how to weigh the portfolios against each other. The non-Base Case portfolios call for the earliest possible retirement of coal plants,

[13] DEC IRP Report at 12.
[14] Docket No. 2019-226-E - Order No. 2020-832 (Dec. 23, 2020) at 9. ("DESC IRP Order") (emphasis added).
[15] DESC IRP Order at 18. (emphasis added)

while others rely on Duke's economic modeling to determine when to retire plants. These two approaches produce meaningfully different results, with some coal units retiring three years earlier.[16] Solar deployment varies dramatically; the difference in the two Base Cases is nearly 4 GW across DEP and DEC, while the deep decarbonization scenarios roughly double solar deployment from 8.6 GW in the Base Case without Carbon Policy to 16.4 GW.[17] Two of Duke's scenarios rely on SMRs, one of which requires a unit to be online at the end of 2029. This timeline, by Duke's own estimate, would require development activity to begin in 2021 and construction to begin in 2023.[18]

Q17. DOES THE COMPANY OFFER ANY EXPLANATION OF WHY IT PRESENTED MULTIPLE PORTFOLIOS AND DID NOT IDENTIFY A SINGLE PORTFOLIO AS ITS MOST REASONABLE AND PRUDENT CHOICE?

A17. It does. Company witness Glen Snider expands on this decision. He states:

> In summary, fifteen-year integrated resource plans involve forecasting a multitude of economic, technical, and overall market variables… Uncertainties exist in any single long-range forecast and such uncertainty is exacerbated in an IRP since IRPs are a culmination of several forecasted variables which drive additional complexity into the planning process. The Companies believe that Act 62 recognizes this high degree of long-range uncertainty in that it calls for multiple portfolios to be examined to cover a range of these uncertainties…
>
> Given the varying perspectives of parties to this proceeding, we expect different views on the various portfolios presented in the 2020 IRPs. However, the IRPs as filed present a total plan that can adapt to changing standards, technology and policy decisions. We believe this is consistent with Act 62, which directs the Commission to approve the plan as reasonable and prudent at the time the plan was reviewed by taking into consideration if the plan appropriately balances various criteria addressing reliability, affordability, compliance with environmental regulations,

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[16] "The earliest practicable retirement analysis resulted in the acceleration of Mayo Unit 1 from 2029 in the Base Cases to 2026 and Roxboro units 1 and 2 from 2029 to 2028, joining Roxboro 3 and 4 in that year." DEP IRP Report at 95.

[17] DEP IRP Report at 16.

[18] Exhibit KL-2, Duke Response to SCSBA's Second Request for Production to DEC/DEP ("SCSBA RFP 2") (producing Duke response to DR NCSEA 5-1).

commodity price risk, diversity of supply, and other factors the Commission determines to be in the public interest. The IRPs filed by the Companies accomplish that goal.[19]

Q18. What is your interpretation of this statement?

A18. First, the testimony critically drops the word "most" from the "most reasonable and prudent" provision of Act 62. The Commission is not directed to "approve the plan as reasonable and prudent", it is directed to approve "the most reasonable and prudent plan." This is a crucial distinction and undermines Duke's position that Act 62's requirements can be met by simply providing multiple options for the Commission to review.

Duke is correct that parties will have "different views" on its portfolios. But Duke's submission of six different portfolios does not constitute a single plan; one cannot approve year 1 through 4 of Portfolio A before switching in year 5 through 12 to Portfolio B and then transitioning in year 13 through 15 to Portfolio C. Each of Duke's portfolios was created from internally consistent assumptions, rendering the piecemeal construction of a single portfolio from portions of each meaningless.[20]

Q19. What is your overall observation about Duke's presentation of its portfolios in the IRP?

A19. Duke has failed to identify a Preferred Resource Plan that it contends is the most reasonable and prudent means of meeting its future needs. It has also failed to present a more robust analysis of the relative merits and associated risks of each portfolio. For instance, it did not include a deeper dive into the policy and technology advancements that may be needed for each portfolio and how Duke and other parties might accomplish them. As an example, a deeper analysis of the current state of next-generation nuclear technology might have shown that portfolios requiring SMRs to be online by 2029 may not be reasonable given that development on those units would have to begin this year to meet the timeline.

[19] Snider Direct at 35-36.
[20] This is a major issue with Duke's natural gas forecast, as discussed in Section IV below.

Further, Duke's lack of a robust risk analysis on its existing and planned fossil fuel plants is problematic. Its focus on PVRR comparisons under different fuel costs and CO_2 assumptions fails to quantify risk in any dimension beyond dollars. For instance, Duke made no effort to weigh the likelihood of a high-cost future compared to a low-cost future, despite the fact that its portfolios perform substantially differently under those conditions. It does not contemplate potential federal regulations that may require sizable capital upgrades to its coal fleet that adds risk disproportionately to certain portfolios. By presenting six very different futures with minimal analysis beyond top-level cost estimates to differentiate them, Duke has inappropriately left the Commission with the task of choosing a future for Duke without the requisite information required to make an informed choice.

B. *Duke's IRP Shares Characteristics with DESC's Rejected IRP*

Q20. HAS THE COMMISSION RULED ON ANY IRPS FILED UNDER THE NEW ACT 62 STATUTE?

A20. Yes. The Commission recently ruled on the IRP filed by DESC.[21] It found "significant deficiencies" in the IRP's candidate resource plans, modeling assumptions, and methodologies, and ultimately rejected the IRP.[22] The Commission provided specific direction to DESC to revisit topics such as its load forecasts, natural gas price forecast, energy storage cost assumptions, and modeling methodologies, among others.

Q21. DOES DUKE'S IRP CONTAIN SHORTFALLS THAT THE COMMISSION IDENTIFIED IN DESC'S IRP?

A21. Yes, it does. The Commission specifically criticized DESC's energy storage cost assumptions as "unreasonably high" for using a capital cost of $1,818/kW for systems with a 2022 in-service date, compared to results from the Santee Cooper RFI that showed $1,324/kW for total installed

[21] DESC IRP Order.
[22] *Id.* at 7.

cost for 2022 in-service date projects.[23] By this measure, Duke's battery storage costs are also unreasonably high; Duke assumes an installed cost of [redacted]kW for systems coming online in 2022.[24] The Commission directed DESC to use NREL ATB Low cost assumptions for energy storage, which, when adjusted to nominal dollars, forecast a capital cost of $1,140/kW in 2022, more in line with the RFI results.[25] I discuss Duke's problematic energy storage assumptions later in my testimony.[26]

The Commission also cited DESC for not considering the addition of new resources or PPAs when there was not a capacity need, failing to recognize the potential for energy-only resources to provide savings compared to the running costs of existing resources. It directed DESC to model the addition of new resources earlier in its planning horizon even when there was no capacity need.[27] Duke commits the same error, configuring its model to only allow new resource additions when there was a defined capacity need. This date of first need is forecasted for 2024 for Duke Energy Progress ("DEP")[28] and 2026 for Duke Energy Carolinas ("DEC")[29], potentially delaying cost-saving procurements for between three and five years. This delay is particularly problematic given the recent extension of the ITC; failing to advance renewable development in the next several years will forego the sizable tax benefit that could be passed on to Duke's customers afforded by the ITC extension.

The Commission also found DESC's natural gas forecast methodology, in which it applied escalators to current prices, was problematic as it overemphasized transient short-term market dynamics in its long-range forecast.[30] It noted that DESC's forecast has a consistent

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[23] *Id.* at 50.
[24] Exhibit KL-3, Duke Response to SCSBA RFP 2 (producing Duke response to PSDR3-7 (Confidential - IRP Generic Unit Summary DEC 2020)).
[25] NREL 2020 ATB.
[26] See Section III, *infra*.
[27] DESC IRP Order at 32-33.
[28] Duke Energy Progress Integrated Resource Plan 2020 Biennial Report ("DEP IRP Report") at 114.
[29] Duke Energy Carolinas Integrated Resource Plan 2020 Biennial Report ("DEC IRP Report") at 113.
[30] DESC IRP Order at 67-68.

low bias compared to more robust fundamentals-based modeling such as the Energy Information Administration's ("EIA") 2020 Annual Energy Outlook ("AEO"), and directed DESC to use the high, base, and low cases from AEO 2020. Duke's natural gas forecast differs from DESC, but it also suffers from a mismatch between short-term price signals and fundamentals-based forecast and over-weights prices influenced by short-term volatility. I discuss Duke's natural gas forecast later in my testimony.[31]

Q22. WHAT DO YOU RECOMMEND REGARDING THESE ISSUES?

A22. I recommend that the Commission reiterate its direction on these topics in this proceeding and require Duke to adjust assumptions on capacity additions, energy storage costs, and natural gas forecasts as I discuss below.

C. *Duke Fails to Present Sufficient Analyses Required to Determine the Reasonableness and Prudence of its Portfolios*

Q23. WHAT, IF ANY, COMPARISON DOES DUKE OFFER ACROSS SCENARIOS THAT PROVIDES INSIGHT AS TO WHETHER A PORTFOLIO IS REASONABLE AND PRUDENT OR IS THE MOST REASONABLE AND PRUDENT?

A23. Duke provides basic information on the portfolios themselves (e.g. MW of assets deployed), the estimated present value of the revenue requirement ("PVRR") of the portfolio over the planning horizon, and an estimate of transmission investment required to interconnect the resources in the portfolio.[32] However, Duke's presentation of these figures lacks context.

The primary overview of the IRP Report shows the PVRR excluding the explicit cost of carbon, despite the fact that five of the six portfolios assume a carbon price is present and impacts the results. This makes it appear that the carbon reduction portfolios are considerably more expensive than the base portfolios.[33] However, if one pieces together information from the separate IRP reports, Duke's data shows that after including the cost of carbon, the

[31] See Section IV, *infra.*
[32] DEP IRP Report at 16.
[33] DEP IRP Report at 16.

incremental cost of the deep decarbonization portfolios is considerably lower than it initially appears.

For example, the incremental cost of the 70% CO_2 Reduction: High Wind over the Base without Carbon Policy is shown as \$20.7 billion (35% higher than the base case) in Executive Summary, but this value falls to \$12.4 billion (12.5% higher) with the base CO_2 and fuel cost assumptions when including the explicit cost of carbon in the PVRR, and to \$6.0 billion (5.2% higher) under the high CO_2 and fuel cost assumptions when including the explicit cost of carbon in the PVRR.[34] Additionally, these figures are based on Duke's modeling, which as discussed later, contains several questionable assumptions that, when corrected, could lower the incremental cost of the deep decarbonization portfolios further, and potentially shift which portfolio becomes least-cost. Duke should be directed to clearly present comparisons with potential carbon pricing, consistent with the Commission's finding in the DESC IRP order that "it is in the public interest for the risk of potential carbon pricing to also be considered and balanced" under Act 62.[35]

Q24. ARE THERE OTHER METRICS THAT DUKE PRESENTS TO ASSIST IN THE COMPARISON BETWEEN PORTFOLIOS?

A24. Yes. It produced a heuristic denoted as "Dependency of Technology and Policy Advancement."[36] This qualitative measure represents the Company's observation on the complexity of realizing certain portfolios given the current state of policy and technology. For instance, it considers the Base Case without Carbon Policy portfolio as "Not dependent" on policy and technology evolution, indicating it can accomplish the portfolio's deployment within the existing constructs. The 70% reduction scenarios are denoted as "mostly dependent"

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[34] DEP IRP Report, Tables 12-B and 12-C; DEC IRP Report, Tables 12-B and 12-C.
[35] DESC Order at 20.
[36] DEP IRP Report at 15.

(High Wind) and "completely dependent" (High SMR), suggesting that without substantial technology and policy development these portfolios cannot be realized.[37]

Q25. HOW RIGOROUS WAS DUKE'S ANALYSIS OF THIS HEURISTIC?

A25. It does not appear to be very robust. The Company notes challenges such as technology advancements, operational risks, siting/permitting/interconnection issues, and supply chain development. However, there is no discussion regarding how much of these advances will occur as a baseline in the next ten years, nor discussion about how feasible the policy changes would be to enact. I generally agree with the directionality of Duke's assessments (for instance, it is likely true that deploying SMRs will require more policy and technology advancement than deploying solar and storage), but I do not believe that one could assign a specific dependency score for each portfolio based on data presented in Duke's IRP reports.

D. Duke's Natural Gas Capacity Buildout Plan is Risky and Inconsistent with its 2050 Net-Zero Goals

Q26. HOW DO THE LEVELS OF NATURAL GAS CAPACITY VARY AMONG THE SIX PORTFOLIOS?

A26. There is a considerable variance between the portfolios. The Company currently operates 10,460 MW of natural gas units, split roughly equally between combustion turbines ("CTs") and combined-cycle ("CC") units.[38] Table 1 below shows the proposed incremental capacities under the various portfolios.

	By 2035			By 2041		
	CC	CT	**Total**	CC	CT	**Total**
2020 Capacity	4,940	5,520	**10,460**	4,940	5,520	**10,460**
Incremental Capacity						
Base without Carbon Policy	3,672	5,941	**9,613**	4,896	12,796	**17,692**
Base with Carbon Policy	3,672	3,656	**7,328**	4,896	10,054	**14,950**
Earliest Prac. Coal Retirement	3,672	5,941	**9,613**	3,672	10,968	**14,640**
70% CO2: High Wind	3,672	2,742	**6,414**	3,672	5,484	**9,156**
70% CO2: High SMR	2,448	3,656	**6,104**	2,448	6,398	**8,846**
No New Gas Generation	0	0	**0**	0	0	**0**

[37] DEP IRP Report at 16.
[38] 2020 IRP_ Model Inputs_NON-CONFIDENTIAL.

Table 1 - Natural Gas Additions by Portfolio

By 2035, the first three scenarios add three new 1,224 MW CCs while increasing CT capacity by roughly two-thirds (Base with Carbon Policy) or more than double (Base without Carbon Policy and Earliest Practicable Coal Retirement). The 70% CO2: High Wind adds fewer CTs through 2035, offset by increasing battery deployment. Unsurprisingly, the No New Gas Generation portfolio adds no new gas generation.

As dramatic as are the additions by 2035, the additional builds through 2040 are truly staggering. The two Base cases each add another 1,224 MW CC facility. The Base without Carbon Policy more than doubles incremental CTs, bringing nearly 7 GW of additional capacity online by 2041. The Base with Carbon Policy portfolio adds nearly as much, with 6.4 GW of new CTs. These additions represent the largest proposed natural gas expansion of any utility in the country by far.[39] Figures 1 and 2 below show the annual additions under each scenario, revealing that much of the natural gas build that was modeled rests just outside of the 15-year planning horizon in Duke's IRP.

[39] *The Dirty Truth about Utility Climate Pledges*, Sierra Club, January 2021. Available at https://www.sierraclub.org/sites/www.sierraclub.org/files/blog/Final%20Greenwashing%20Report%20%281.22.2021%29.pdf.

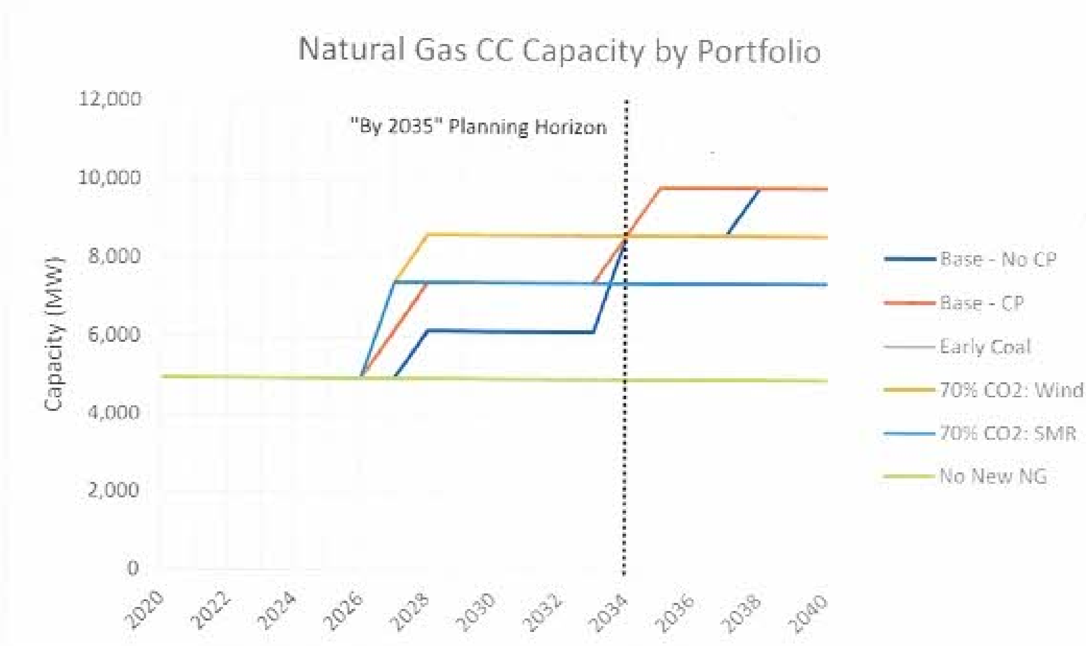

Figure 1 - Natural Gas CC Additions by Scenario

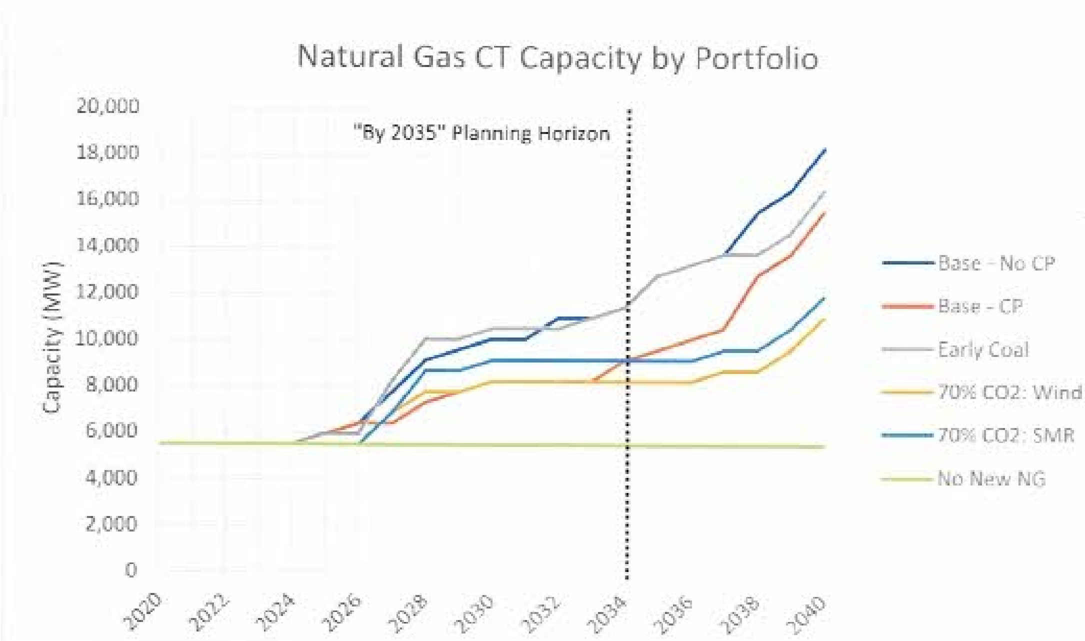

Figure 2 - Natural Gas CT Additions by Scenario

Q27. WHAT TYPES OF RISK ANALYSIS DID DUKE PERFORM WITH RESPECT TO ADDING THIS MUCH NEW NATURAL GAS CAPACITY?

A27. It did very little risk analysis. Duke did include a low and high natural gas fuel cost forecast sensitivity,[40] but it simply assumes that firm capacity to deliver this gas to all its new CC units will be available from "new or upgraded capacity" at a constant price.[41] Given the recent cancellation of the Atlantic Coast Pipeline, the recent $1.2 billion write down by NextEra on its Mountain Valley natural gas pipeline project, and the increasingly challenging siting and permitting environment for new or upgraded capacity, this assumption is not without risk.[42] Further, the Company does not plan on contracting for firm natural gas delivery for its CT units, despite adding nearly 6 GW by 2035 and up to 12.8 GW by 2040 in some scenarios that will be utilized during cold winter mornings and evenings at the exact same time when the natural gas distribution system will be under stress from building heating loads.

Q28. Are Duke's plans regarding the addition of new natural gas units consistent with its plans to decarbonize by 2050?

A28. No, at least not without significant risk of stranding assets or becoming overly dependent on emerging technology. Duke has a corporate goal to have net-zero carbon emission by 2050.[43] This is not the same as emitting zero carbon, as Duke specifically contemplates the deployment of carbon capture and sequestration technology in the future.[44] It also assumes renewable gas and hydrogen will be widely available to power units that previously ran on natural gas and that "zero emission load following resources" ("ZELFRs"), such as SMRs and natural gas combined cycle units ("NGCC") with carbon capture and sequestration ("CCS"), will be commercially available by 2035.[45]

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[40] Which has its own substantial issues, as discussed in Section IV *infra*.
[41] Exhibit KL-4, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-45); Exhibit KL-5, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-55).
[42] In a telling signal, NextEra's announcement of its $1.2 billion write down on its pipeline was coupled with an announcement of adding as much as 30 GW of renewable projects to its portfolio, well above analyst estimates of 20 GW. https://www.reuters.com/article/nextera-energy-results/update-1-nextera-energy-posts-loss-on-pipeline-write-down-idUSL4N2K12N3.
[43] https://www.duke-energy.com/Our-Company/Environment/Global-Climate-Change
[44] Duke Energy 2020 Climate Report ("Climate Report") at 4. https://www.duke-energy.com/_/media/pdfs/our-company/climate-report-2020.pdf?la=en. Accessed 1/20/21.
[45] Climate Report at 5.

Q29. ARE THESE TECHNOLOGIES AVAILABLE TODAY?

A29. No, these technologies are not yet commercialized. Although the energy industry will certainly change over the coming 15 years, there is much uncertainty as to whether resources such as SMRs and NGCC with CCS will have been commercialized by that time, or, if they are, if they will be cost effective compared to other technologies. There is also an open question of whether the infrastructure required to sequester the CO_2 captured from NGCC units will be cost-effective or whether Duke's geographic territory has suitable reservoirs. Notably, Duke acknowledges this uncertainty and does not include any CO_2 transport costs outside the fence line, noting these costs are "highly depending on location, as well as the cost of injection."[46]

Renewable natural gas and hydrogen infrastructure to displace natural gas has recently emerged as area of intense interest. It is possible that a new industry will emerge that can supply zero-carbon fuel to Duke's natural gas fleet, but current units cannot burn pure hydrogen without modifications. It is unclear whether Duke will install units that have this capability in the future ahead of widespread deployment of hydrogen as a fuel stock. If they do not, then additional assets will be at risk of stranding or require substantial and costly modifications if and when a switch to hydrogen becomes commercially viable.

Q30. HOW DOES DUKE SEE ITS NATURAL GAS FLEET EVOLVING IN THE FUTURE?

A30. Duke assumes that its natural gas fleet will "shift from providing bulk energy supply to more of a peaking and demand-balancing role."[47] This is consistent with the deployment of large quantities of renewable energy and energy storage that are also required in the net-zero scenarios. However, Duke's Base case portfolios in the IRP double the capacity of high-capacity factor NGCC units by 2040, while other scenarios add between 50% and 75% more NGCC capacity. Much of this capacity is added after 2032, only 18 years before the planned net-zero date.

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[46] Climate Report at 24.
[47] Climate Report at 2.

These units are designed to run at high capacity factors and are not as flexible as combustion turbine units. Building this much new NGCC capacity, with less than two decades until the Company's planned transition to net-zero, risks stranding billions in dollars of assets. While Duke did perform a nominal stranded asset sensitivity, it assumed that natural gas units would have a 25-year life.[48] However, if Duke is serious about reaching net zero in 2050, this assumption appears incorrect for the thousands of MW of new capacity added after 2030.

Q31. ASIDE FROM THE GAS DEPLOYMENT, WHAT OTHER CAPACITY IS REQUIRED IN THE NET-ZERO CARBON SCENARIO?

A31. Duke foresees a massive ramp up in both renewable generation capacity and energy storage. In its illustrative example, the Company projects going from 5 GW of renewables in 2019 to 31 GW in 2040 and 47 GW in 2050. Energy storage increases from 2 GW in 2019 to 7 GW in 2040 and 13 GW in 2050.[49] These deployment levels are not without their challenges, but unlike some of Duke's other resource assumptions, the underlying renewable and energy storage technologies are mature and widely available.

Q32. WHAT STEPS COULD DUKE TAKE NOW TO INCREASE THE LIKELIHOOD OF ATTAINING ITS NET-ZERO GOALS WHILE MINIMIZING THE RISK OF STRANDING NATURAL GAS ASSETS?

A32. The Company should ramp up its deployment of renewable generation and storage in the near term. Duke's 2050 goals call for massive quantities of new renewables and storage over the next 30 years, and yet it backloads much of these capacity additions. The recent passage of the ITC offers a chance to more economically deploy solar and solar plus storage projects prior to 2025 to jumpstart Duke's progress towards its goals.

Q33. PLEASE SUMMARIZE THE RISKS ASSOCIATED WITH DUKE'S SIZABLE NATURAL GAS DEPLOYMENT ASSUMPTIONS.

[48] IRP Report at 137.
[49] Carbon Report at 26.

A33. Duke models huge increases in natural gas capacity, both from NGCC and combustion turbine units. While it presented results primarily through 2035, it modeled scenarios through 2040. The latter build schedules show even more natural gas deployment in the second half of the 2030s, less than two decades before the Company's net-zero pledge. Further, the construction of more natural gas capacity will increase the Company's customers' exposure to natural gas prices. Since Duke is able to pass through fuel costs as an expense, it would be the retail customers who would see higher bills from elevated natural gas prices.

In the near term, Duke assumes firm fuel transport for its NGCC units will be readily available at the same price as today, despite the increasing regulatory risk associated with new pipeline capacity. It does not assume firm fuel delivery for its CTs, despite their increasing usage during winter mornings and evenings when building heating load is highest. These are substantial cost and operational risks that are not well accounted for in the IRP.

Duke assumes substantial technological evolution in its 2050 net-zero goal, which directly informs the 70% CO_2 reduction scenarios in the IRP. NGCC with CCS or broadly-available hydrogen fuel is required to continue to run its turbines. Further, turbines that are designed for hydrogen combustion would need to become the norm and Duke would need to begin to install these well before 2050 lest then-existing assets require major upgrades. The energy sector will certainly evolve in the coming decades, but Duke's decarbonization scenarios rely very heavily on technology with speculative commercial viability.

By contrast, renewable generation and energy storage are mature technologies that can be incorporated earlier and in larger quantities than assumed in Duke's plan. Although the Company's IRP scenarios include sizable renewable buildouts, more could be done earlier in the timeline to reduce reliance on construction of substantial natural gas capacity later in the planning period. This is particularly true given the recent extension of the federal ITC for solar and solar plus storage systems.

E. *A Basic Risk Analysis Shows the Benefit of the Early Coal Retirement Option*

Q34. DID DUKE PERFORM ANY QUANTITATIVE RISK ANALYSES AS PART OF ITS RISK ASSESSMENT?

A34. No. As discussed above, the Company's risk assessments were largely qualitative in nature. It presented the results of its various scenarios and sensitivities but did not produce analyses to compare those portfolios across various input assumptions.

Q35. HOW DID DUKE MODEL CARBON PRICING IN ITS IRP?

A35. Duke modeled a carbon price as a production cost adder in all portfolios except for the Base Case without Carbon Policy. The carbon price commences in 2025 at $5/ton and increases by $5/ton and $7/ton annually in the base and high CO_2 price sensitivities.[50] By 2050, the carbon price has escalated to $130/ton and $180/ton in the base and high case, respectively.

Q36. HOW DOES THIS CARBON PRICE COMPARE TO RECENT CO_2 PRICING ANNOUNCEMENTS?

A36. It is substantially under several alternative proposals that Duke mentions in its IRP, including Energy Innovation and Carbon Dividend Act (H.R. 763) ($15/ton escalating at $10 /ton per year) and the American Opportunity Carbon Free Act of 2019 (S. 1128) ($52/ton escalating at 8.5% per year).[51] It is also substantially under the recently announced carbon price from New York Department of Environmental Conservation, which was calculated at $125 / ton in 2020 before increasing to $373 / ton in 2050.[52]

Q37. DOES DUKE MODEL ANY INCREASED REGULATORY COSTS THAT MAY IMPACT THE ECONOMICS OF CONTINUING TO RUN ITS COAL PLANTS?

A37. No. Duke did not construct a high- or low-cost sensitivity for fuel or fixed O&M costs for coal units, nor did it model retirement outcomes under different regulatory regimes. Given recent developments at the federal level, it is highly likely that new regulations will be enacted that

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[50] DEC IRP Report at 153.
[51] DEC IRP Report at 153.
[52] 2050 carbon price is $178 / ton in $2020. Assuming inflation at 2.5% per year produces a 2050 nominal price of $373.37 / ton. https://www.dec.ny.gov/press/122070.html.

substantially change the cost of keeping coal units online, and the risk of such regulations is likely highly asymmetric towards increasing costs rather than reducing them.[53]

Q38. WHAT INFORMATION DID DUKE PROVIDE REGARDING THE PERFORMANCE OF THEIR PORTFOLIOS UNDER DIFFERENT FUEL AND CO_2 COST ASSUMPTIONS?

A38. Duke provided the PVRR values for each scenario, highlighting the base fuel case that excluded the explicit cost of carbon.[54] Under this approach, it appears the Base without Carbon Policy has the lowest PVRR across all sensitivities, with the Base with Carbon Policy and Earliest Practicable Coal Retirement costing about 1% to 6% more and the 70% CO_2 Reduction and No New Gas portfolios costing about 13% to 41% more.

However, these figures do not tell the complete picture, as, with the exception of the Base without Carbon Policy, they do not include the cost of carbon that is modeled in the scenario. When these costs are added back in, the performance of the portfolios changes substantially. After making this change, the Base case Without Carbon Policy does not have the lowest PVRR in 5 of the 6 sensitivities with a carbon price, and the cost premium for the Earliest Practical Retirement portfolio is nearly erased, from an average of 5% without carbon

[53] President Biden's highly publicized commitment to 100% decarbonization of the electric power sector by 2035 will necessarily require much more stringent regulation of coal-fired power plants than exists today. *See* https://www.washingtonpost.com/climate-environment/2020/07/30/biden-calls-100-percent-clean-electricity-by-2035-heres-how-far-we-have-go/?arc404=true. Moreover, in his January 20 Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, President Biden called for the U.S. Environmental Protection Agency ("EPA") to review and consider suspending, revising, or rescinding many Trump Administration actions weakening the regulation of coal-fired power plants, including, but not limited to "National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units – Reconsideration of Supplemental Finding and Residual Risk and Technology Review," 85 Fed. Reg. 31286 (May 22, 2020). In addition, the D.C. Circuit Court of Appeals recently affirmed EPA's finding that greenhouse gas emissions endanger public health and welfare, and that EPA is thus required by the Clean Air Act to adopt to regulations to address such emissions from new and existing power plants. With respect to existing power plants, that means that EPA must, under 42 U.S.C. § 7411, establish the "best system of emission reduction ["BSER"] that has been adequately demonstrated." The D.C. Circuit rejected the Trump Administration's conclusion – contrary to that of the Obama Administration – that BSER may not include measures beyond the fence line of the power plant, such as mandating the replacement of existing carbon-emitting resources with new zero-emission resources. *American Lung Association et al. v. Environmental Protection Agency et al.*, Case No. 19-1140 (D.C. Cir. Jan. 18, 2021. None of this bodes well for the future of existing coal-fired power plants.

[54] DEC IRP Report at 17.

costs to an average of 1% with carbon costs. Further, the calculated cost premium of the deep decarbonization scenarios fall substantially to 3% to 24% (down from an increase of 13% to 41%), despite Duke's questionable inputs assumptions.[55]

Q39. HAVE YOU PRODUCED ANY ANALYSIS THAT ALLOWS ADDITIONAL COMPARISON OF THE SCENARIOS?

A39. Yes. I ran a cost range and minimax regret analysis on Duke's scenarios that was also performed in the DESC IRP.[56] As in the DESC IRP proceeding, these straight-forward analyses provide insight on how portfolios may perform under a variety of future scenarios. Although fairly simple, they highlight the importance when determining the most reasonable and prudent plan of looking beyond a portfolio that is assumed least-cost in limited scenarios.

Q40. WHAT WAS THE RESULT OF THESE ANALYSES?

A40. When the explicit cost of carbon is considered, the Earliest Practical Retirement portfolio emerges as the most robust of those scenarios that do not specifically target deep decarbonization. Table 2 below shows the cost range and minimax regret analysis for each of the portfolios and the CO_2 and fuel cost sensitivities. Note that these values still contain Duke's flawed natural gas price forecasts, which are substantially lower than fundamentals-based forecasts, and inflated energy storage costs. If the Commission were to require Duke to update its natural gas forecasts, scenarios with higher natural gas usage would be more costly.

[55] Tables 12-B and 12-C, DEP IRP Report and DEC IRP Report.
[56] Direct Testimony of Kenneth Sercy on Behalf of the South Carolina Solar Business Alliance, Inc at 37, Docket NO. 2019-226-E.

PVRR ($b)	Base w/o Carbon	Base w/ Carbon	Earliest Coal	70% CO_2: High Wind	70% CO_2: High SMR	No New NG
High CO_2-High Fuel	116.5	113.7	114.5	122.5	117.3	129.7
High CO_2-Base Fuel	106	104.5	105.3	115.6	110.4	123.1
High CO_2-Low Fuel	99.1	98.4	99.3	110.8	105.6	118.4
Base CO_2-High Fuel	109.6	107.8	108.9	118.5	113.4	125.8
Base CO_2-Base Fuel	99.2	98.8	99.7	111.6	106.5	119.2
Base CO_2-Low Fuel	92.4	92.6	93.7	106.9	101.8	114.6
No CO2-High Fuel	89.2	90.4	93.3	107.4	102.3	114.3
No CO2-Base Fuel	79.8	82.2	84.2	100.5	95.5	108.2
No CO2-Low Fuel	73.3	76.4	78	95.8	90.7	103.5
Cost Range	43.2	37.3	36.5	26.7	26.6	**26.2**
Max Regret	43.2	**40.4**	41.2	49.2	44	56.4

Table 2 - Cost Range and Minimax Analysis – Carbon Cost Included

Q41. PLEASE INTERPRET THE RESULTS OF THIS ANALYSIS.

A41. The Cost Range of each scenario represents the highest PVRR less the lowest PVRR. It is a measure of sensitivity of a scenario to fuel and CO_2 cost inputs. Unsurprisingly, the deep decarbonization scenarios on the right side of the table have the lowest cost range as they contain the least fossil fuel, and thus the lowest exposure to both CO_2 and natural gas prices.[57] The Base without Carbon policy has the highest range of the set, demonstrating the risk of assuming low costs and no CO_2 and finding oneself in a policy world with high fuel costs and high CO_2 costs. Of the three scenarios on the left side, the Earliest Practicable Coal Retirement has the lowest Cost Range result, again showing that eliminating coal earlier while adding more renewables reduces exposure to CO_2 and natural gas costs.

The Max Regret value represents the difference between a portfolio's highest PVRR and the lowest PVRR of all the scenarios. This represents the worst-case outcome of choosing an alternative portfolio compared to selecting the lowest possible portfolio under the least cost option. The low PVRR is established by the Base without Carbon No CO_2-Low Fuel sensitivity at $73.3 billion. Based on this figure, the lowest Max Regret score is from the Base with Carbon, followed closely by the Earliest Practicable Coal Retirement scenario. These have

[57] DEC IRP Report at 8.

Max Regret scores \$2.8 and \$2.0 billion lower than the Base without Carbon Policy portfolio, suggesting that selecting these two portfolios is less risky than the Base without Carbon Policy.

The Base Case with Carbon has the lowest max regret value at \$40.4 billion, followed by the Earliest Practical Coal Retirement at \$41.2 billion. The difference between the two amounts to less than 1% of the total PVRR of the portfolios. Importantly, these results do not contemplate new federal or state regulations that may require substantial capital cost investments to maintain the compliance of fossil fuel plants which would be in addition to any variable costs such as fuel and CO_2 that are included. Further, the risk of these new regulations is much higher in the Base cases where coal is assumed to operate longer than the deep decarbonization portfolios when coal plants are retired earlier. This likely understates the cost of owning and operating coal plants compared to baseline included in Duke's IRPs. If this risk were more rigorously quantified, it very well may have an expected value greater than the \$0.8 billion noted above.

Q42. DO THE RELATIVELY HIGH MAX REGRET RESULTS FOR THE 70% CO_2 REDUCTION AND NO NEW GAS SCENARIOS CONCERN YOU?

A42. No. Much of the incremental cost of the 70% CO_2: High Wind portfolio over the Earliest Practical Coal Retirement is due to Duke's assumptions of transmission cost. However, the Company has not rigorously analyzed these costs nor considered the cost savings that may come from broader regionalization.[58] Similarly, the No New Natural Gas scenario is hampered by Duke's unreasonable energy storage cost assumptions. Had more reasonable costs been included, the cost of adding standalone storage and solar plus storage would have been reduced and closed the gap between the deep decarbonization portfolios and the others.

Q43. WHAT IS YOUR CLOSING OBSERVATION ABOUT DUKE'S RISK ASSESSMENTS?

A43. Duke failed to present robust, quantitative risk analyses. It focused primarily on the portfolio PVRR under different natural gas and CO_2 cost assumptions but did little to compare the

[58] Exhibit KL-6, Duke Response to SCSBA RFP 2 (producing Duke response to DR NCSEA 2-6).

relative risk of the portfolios against each other. The basic minimax analysis above shows that despite the Base without Carbon Policy scoring the lowest PVRR, it was not the least risky plan. Although the analysis above is hampered by Duke's unreasonable input assumptions, a strong case can be made that the Earliest Practicable Coal Retirements case is the most robust of the non-deep decarbonization portfolios. This result is also supported by the asymmetric likelihood that regulatory costs will rise on coal plants before they fall, further increasing the risk associated with the continued operation of Duke's coal fleet.

III. DUKE'S MODELING ASSUMPTIONS REQUIRE MODIFICATION

Q44. PLEASE PROVIDE AN OVERVIEW OF THIS SECTION OF YOUR TESTIMONY.

A44. In this section, I discuss numerous assumptions that Duke made in its IRP modeling. I begin by highlighting the recent extension of the federal ITC and its impact on project economics. I continue to evaluate Duke's cost and operational assumptions for standalone solar, standalone storage, and solar plus storage projects. Finally, I review Duke's development timeframes for the particularly challenging SMR and pumped hydro technologies.

Q45. WHAT ARE YOUR PRIMARY CONCLUSIONS?

A45. The opportunity afforded by the ITC extension should not be bypassed. The two-year extension opens a window where Duke could deploy substantially more solar and solar plus storage projects early in its IRP planning horizon while allowing customers to reap the financial benefits. Although this change occurred after Duke completed its modeling, it is of sufficient scale and consequence that the Commission should direct Duke to update its modeling to incorporate the new law.

Overall, Duke's cost and operation assumptions on solar and storage are mixed. I find that its capital cost assumptions for solar are reasonable (although must be updated to account for the ITC extension), but its fixed O&M cost assumptions do not reflect the technology improvements in that sector. Duke's battery capital costs are substantially overinflated and